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Excessive Price Volatility in the California Ancillary Services Markets: Causes, Effects, and Solutions

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Abstract

On 31 March 1998, restructuring of the California electricity industry brought the forces of the free market into a sector of the economy that had long been regulated. While the new market structure is similar to that of many other restructured markets in several respects, the competitive procurement of ancillary services by the California Independent System Operator (CAISO) is an almost unique feature. These markets are shown to exhibit extreme price volatility that has resulted in high procurement costs for California electricity consumers. An analysis of the amount of generation offered in the AS markets relative to the known purchase requirement of CAISO shows that withholding of capacity in certain hours has probably occurred and this suggests that generators have exercised market power. During the first of operation, one response to these problems by the CAISO Board of Governors, with the approval of the Federal Energy Regulatory Commission (FERC), has been the imposition of a fixed price cap, the level of which has been adjusted between \$250/MW and \$750/MW. Subsequent to the period of study, CAISO has implemented several reforms intended to curb market power. Mechanisms used in other restructured electricity markets could have been considered, such as threats of regulatory action and use of hedge contracts.

1. Introduction: Overview of the California Ancillary Services Markets

On 31 March 1998, restructuring of the California electricity industry brought the forces of the free market into a sector of the economy that had long been regulated. Similar to electricity market reforms in other regions of the world, the changes in California's industry involved *unbundling* the various services offered by electricity utilities. Now, instead of allowing the utilities to control all aspects of electricity supply, the California state legislators passed Assembly Bill (AB) 1890 which separates the industry into:

1. a competitive part consisting of the generation and retail functions, and
2. a regulated monopoly structure that retained control over the transmission and distribution systems.

In order to operate this new market structure, two non-profit corporations were created: the California Independent System Operator (CAISO) and the California Power Exchange (CalPX). The former provides transmission services to all electricity suppliers, while the latter operates forward competitive energy markets into which generators sell electricity. In addition, the CAISO manages real-time imbalance energy and ancillary services (AS) markets. This paper covers the first year of operation of AS markets. The imbalance energy market is effectively a spot market for wholesale electricity, while AS are required under North American Electric Reliability Council (NERC) and Western System Coordinating Council (WSCC) rules to safeguard the reliability of the transmission grid.

Each energy service provider (ESP) can choose to provide its own AS, and CalPX has requested that the Federal Energy Regulatory Commission (FERC) approve a block forward AS market. However, to date, virtually all AS are procured in CAISO's first in the world open competitive markets for procurement of AS. That is, the CAISO accepts generator bids and buys AS on behalf of all loads. The AS procured in this way are:

- *Regulation service:* generation that is available and running, and can be used to maintain real-time balance in the transmission system
- *Spinning reserves:* generation that is running with additional capacity available
- *Non-spinning reserves:* generation that is available but not running
- *Replacement reserves:* generation that is capable of starting up[1]

In addition, *reactive power support* and *black-start generation capability* are AS that are procured through long-term contracts. For a more complete description of the restructured California electricity industry, see either CAISO 1999a or Gómez, Marnay, Siddiqui, Liew, and Khavkin 1999.

While the CalPX day-ahead energy prices and CAISO real-time imbalance energy prices evolved with predictable seasonal patterns and in lockstep with prices in forward energy markets during the first year of deregulation (1 April 1998 to 31 March 1999), AS prices were higher and more volatile than expected. Although some price volatility that reflects

[1] California Independent System Operator (CAISO). *Annual Report on Market Issues and Performance, June 1999* (available at http://www.caiso.com), 1999a.

temporary scarcity is desirable in competitive markets to provide economic signals to agents (i.e., provide *scarcity rents*), extreme volatility of the sort experienced by the California AS markets may be symptomatic of design flaws that inhibit, rather than promote, competition and risk unjustified wealth transfers (i.e., provide *monopoly rents*). The existence of market power and consequent wealth transfers do not *per se* imply any collusive activity on part of the generators, but, in the interests of promoting economic efficiency and fairness, market design should seek to limit these adverse outcomes. The collection of scarcity rents, on the other hand, sends market signals that can attract new entrants and may well be necessary to cover generators' fixed costs, which may not be recovered if prices are always close to marginal cost. Hence, in a situation of extreme price volatility, the market structure and its results need to be examined. Unfortunately, actually determining whether a specific price spike truly reflects scarcity or not is a non-trivial exercise. Of course, the beneficiaries of spikes, typically generators, argue that scarcity exists, while electricity purchasers argue the contrary. A recent study (Gruenspecht and Terry 2000) has explored the national consequences of market power in a restructured industry.

In this paper, the price data from the first year of the competitive California AS markets are examined to see what, if anything, went awry. In Section 2, a measure of price volatility is defined and applied to the price data from California. Empirical evidence is then presented to support the proposition that, indeed, there was excessive price volatility and that market power was being exercised. The average price markups in the AS markets are analyzed to show that departures from competitive prices were concomitant with withholding of capacity from the markets, implying that market power may have caused such excessive price volatility. The price spikes are shown to have had a tremendous impact on the California electricity market by raising the cost of procuring AS to almost 12% of the overall value of energy traded in the CalPX during the first year of operation. In Section 3, the CAISO's response to excessive price volatility is examined. In Section 4, methods for regulating price volatility in other electricity markets are explored to determine whether they might be applicable to the California AS markets. Finally, recommendations and concluding remarks appear in Section 5.

2. Price Volatility and Its Consequences for the California Ancillary Services Markets

2.1. What is Price Volatility?

Before proceeding to analyze the volatility of AS prices in California, it is first necessary to define *price volatility*. Intuitively, price volatility is a measure of the dispersion or fluctuation in prices observed over some time period, e.g., hourly, daily, weekly, etc. In the context of financial markets, the *volatility* of the rate of return on an asset is often calculated as either the *variance* or the *standard deviation (SD)* of the return.[2] However, the standard deviation may not be an effective tool for comparing price volatilities because this statistic is not unit free. For example, consider the following case in which the summary statistics of two hypothetical variables over a given time period are tabulated:

[2] Miller, M. H. "Index Arbitrage and Volatility." *Financial Innovations and Market Volatility*. Cambridge, MA: Basil Blackwell, Inc., 1991.

Variable	*Mean*	*Standard Deviation*	*Coefficient of Variation*
X	100	1	0.01
Y	50	1	0.02

Table 1 Measuring Volatility

From Table 1, it can be seen that the standard deviations of both variables are equal. Thus, based on the standard deviations alone, it is not obvious which variable is more volatile. Nevertheless, it appears that variable *Y* is more volatile since a standard deviation of 1 is larger relative to its *mean* than it is relative to variable *X*'s mean. Hence, in this paper, the convention adopted is that the *coefficient of variation (COV)*[3] of a price (or, the standard deviation to mean ratio) over a specified time period measures the volatility of the price.

2.2. Empirical Evidence of Price Volatility

In order to determine whether the volatility of a commodity's price (as measured by the *COV*) is in fact excessive, it is necessary to compare its *COV* with those of other asset prices. This is because *volatility* is a relative concept, and thus, the *COVs* of asset prices cannot be considered in isolation. In Table 2, some summary statistics presented for three California electricity markets during the first year of operation: the CalPX day-ahead energy market, the CAISO real-time energy market, and CAISO AS markets. Here, *peak* refers to hours 7 through 22 of a trading day, while *off-peak* refers to the rest[4].

	Mean	Std.Dev.	COV
CalPX Peak	$28.18/MWh	$13.05/MWh	0.46
Real Time Peak	$27.97/MWh	$16.42/MWh	0.59
Regulation Peak	$11.36/MW	$10.80/MW	0.95
Spinning Reserve Peak	$16.09/MW	$24.77/MW	1.54
Non-Spin Reserve Peak	$9.81/MW	$18.40/MW	1.88
Replacement Reserve Peak	$10.56/MW	$20.11/MW	1.90
CalPX Off-Peak	$16.72/MWh	$7.49/MWh	0.45
Real Time Off-Peak	$15.24/MWh	$7.51/MWh	0.49
Regulation Off-Peak	$16.97/MW	$21.57/MW	1.27
Spinning Reserve Off-Peak	$5.30/MW	$7.70/MW	1.45
Non-Spin Reserve Off-Peak	$2.29/MW	$2.62/MW	1.14
Replacement Reserve Off-Peak	$2.12/MW	$3.01/MW	1.42

Table 2 Average Weekly Energy and AS Prices in California from 1 April 1998 to 31 March 1999 (Sources: CAISO and CalPX)

The *COVs* of the AS average weekly prices are clearly greater than those of the energy prices in both peak and off-peak hours, and therefore, indicate that price volatility in the AS markets has been high compared to that of energy prices. The price volatility in the

[3] Coefficient of Variation = Standard Deviation/Mean (if mean = 0, then set COV = ∞)
[4] Note that this is not consistent with the usual California definition of "peak," which is 1200 to 1800 during the summer season.

AS markets is apparent when the average weekly energy and AS prices are plotted (see Figure 1 and Figure 2).

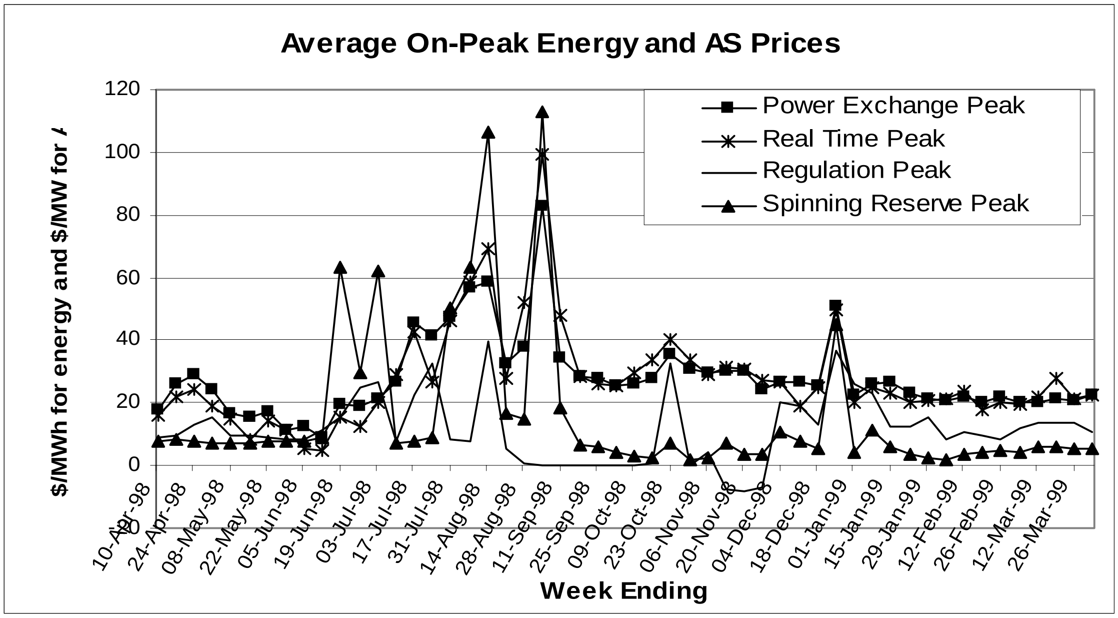

Figure 1 1998-99 Average Weekly On-Peak Energy and AS Prices in California from 1 April 1998 to 31 March 1999 (Sources: CAISO and CalPX)

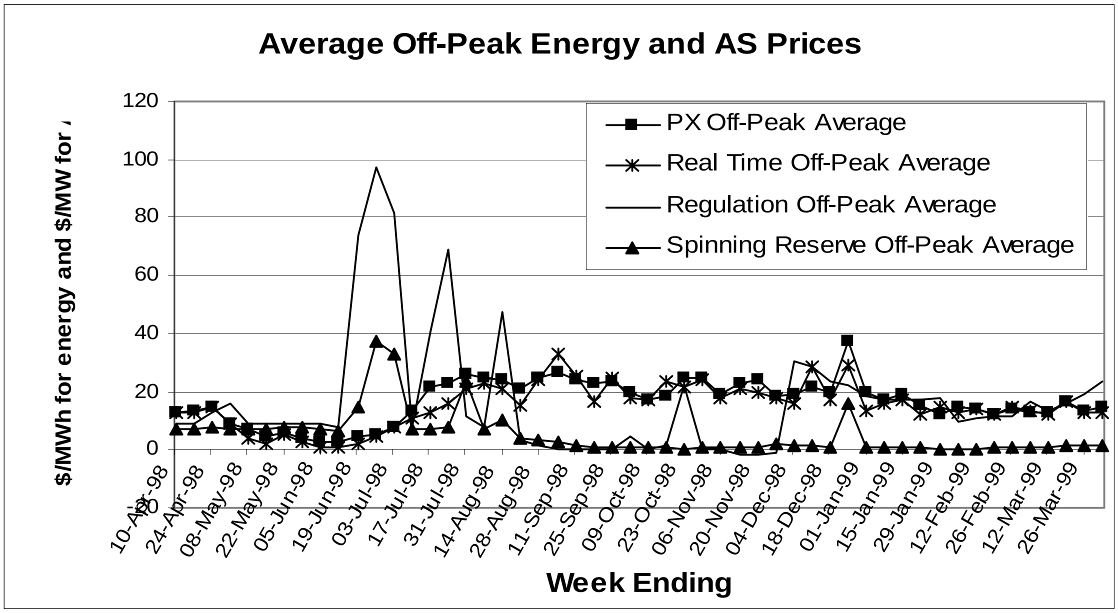

Figure 2 1998-99 Average Weekly Off-Peak Energy and AS Prices in California from 1 April 1998 to 31 March 1999 (Sources: CAISO and CalPX)

2.3. Possible Causes of Price Volatility

Traditionally, utility regulation has levelized retail prices, even though the costs of producing electricity are inherently volatile due to the non-storability of electricity[5]. This has tended to distort price signals in regulated markets, leading to under-pricing of electricity during peak hours and over-pricing during off-peak hours. Consequently, electricity demand is highly price inelastic during high cost, high wholesale price periods, implying that from an economic standpoint, electricity has been over-consumed during peak hours and under-consumed during off-peak hours[6]. Due to restructuring and competition, however, retail customers should ultimately see more volatile prices since the last accepted bid from a competitive firm seeking to maximize profit will tend to set the wholesale price equal to the marginal cost of that bidder. However, because of a legislated price cap, rigid contract provisions, and simple resistance, few customers yet see the volatility of wholesale price reflected in their bills. Prices will tend to be volatile because diverse generators are setting price at different times, and because costs themselves tend to be rather variable as fuel prices vary. Hence, price volatility in a competitive market can be explained simply by the variable nature of costs of production, e.g., fuel costs or availability of hydropower, by fluctuations in supply and demand, and by occasional collection of scarcity rents during times of supply shortfall. However, during the transition to a competitive environment, customer energy prices are subject to a legislated cap, which extends the highly inelastic demand seen in regulated markets. Furthermore, under the conditions of a vertical demand curve, bidders are frequently able to exercise market power and collect monopoly rents. Therefore, under highly inelastic demand, prices can become extreme. The demand for AS tends to be tied closely to electricity demand because AS requirements at any time are determined by system load.

The sort of price volatility experienced in the CAISO AS markets during 1998-99 does *not* seem to be caused by the usual currents of a competitive market, however. Indeed, much of this price volatility can be attributed to the presence of *market power* in the AS markets and perverse incentives for suppliers not to bid into the AS markets. Evidence of market power can be inferred from the average *bid sufficiency index (BSI)*, an indicator used by the CAISO to measure the adequacy of supply in the AS markets[7]. Under high load conditions, in-state generating and import capacity may be stretched leading to a low *BSI*, but under low load conditions, a low value of the *BSI* may suggest withholding of capacity from the AS markets, thereby leading to higher prices. From the following

[5] Bonbright, J.C. *Principles of Public Utility Rates*. New York, NY: Columbia University Press, 1961.

[6] A recent study (Alvarado and Rajaraman 2000) has attempted to use frequency-domain methods in order to identify periodicity in electricity prices.

[7] The *BSI* for hour *t* is:

$$BSI_t\% = \frac{\sum_{i=1}^{n} q_{it}}{D_t} * 100$$

where

q_{it} is generator *i*'s supply bid for hour *t* (there are *n* firms)
D_t is the total AS capacity demanded in hour *t*

tables and figures, it can be seen that typically the lower the *BSI*, the greater the average AS price[8] (see Table 3, Table 4, Figure 3, Figure 4, Figure 5, and Figure 6). The results in Table 3 and Table 4 indicate that AS prices and BSI are negatively correlated, with the regulation reserve AS exhibiting the weakest relationship between price and *BSI*[9]. When the AS *BSI* are plotted against the prices and are fitted with ordinary least squares (OLS) trendlines[10] (as in Figure 3, Figure 4, Figure 5, and Figure 6), the negative relationship becomes evident. This analysis lends credence to the hypothesis that high AS prices occurred precisely during those periods in which generators were able to withhold capacity. Absent an out-of-market alternative, such as calling generators under reliability must run (RMR) contracts, a *BSI* of less than 100% would imply absolute market power because the CAISO would be required to purchase all of the AS offered at any price. In other words, the totally inelastic nature of the CAISO's demand for AS sets up the conditions for exercise of market power.

Ancillary Service	*Correlation Coefficient*
Regulation	-0.277
Spin	-0.535
Non-Spin	-0.556
Replacement	-0.389

Table 3 Correlation Analysis of AS Prices with BSI During Peak Hours for 1 April 1998 to 31 March 1999 (Source: CAISO)

Ancillary Service	*Correlation Coefficient*
Regulation	-0.094
Spin	-0.700
Non-Spin	-0.826
Replacement	-0.133

Table 4 Correlation Analysis of AS Prices with BSI During Off-Peak Hours for 1 April 1998 to 31 March 1999 (Source: CAISO)

[8] We use monthly average on-peak prices, i.e., twelve data points.

[9] This can be explained in part by the institution of the regulation energy payment adjustment (REPA) from June 1998 to October 1998 by the CAISO in order to increase regulation bid sufficiency. REPA stipulated that generators providing regulation would receive $20/MW or the imbalance energy (real time energy) price (whichever is higher). This may have tempered some of the incentive for generators to withhold capacity from the regulation AS market (see CAISO 1999a for details).

[10] Note that the "best-fit" OLS trendlines are used, i.e., the ones that yield the highest R^2 values. Hence, various regression specifications are obtained.

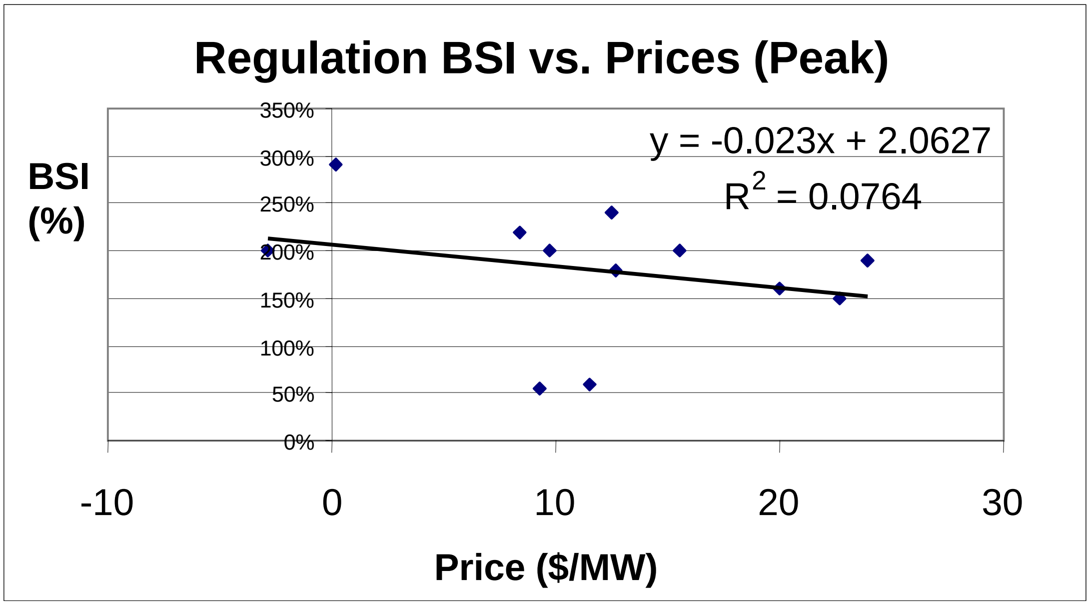

Figure 3 Regulation BSI vs. Price from 1 April 1998 to 31 March 1999 During Peak Hours With OLS Trendline (Source: CAISO)

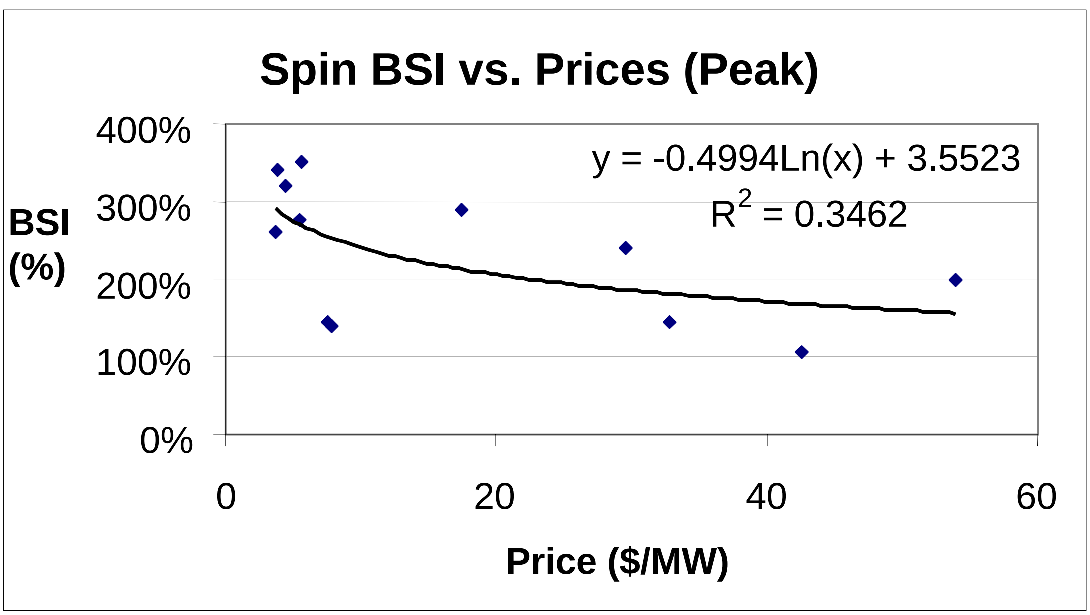

Figure 4 Spinning Reserve BSI vs. Price from 1 April 1998 to 31 March 1999 During Peak Hours With OLS Trendline (Source: CAISO)

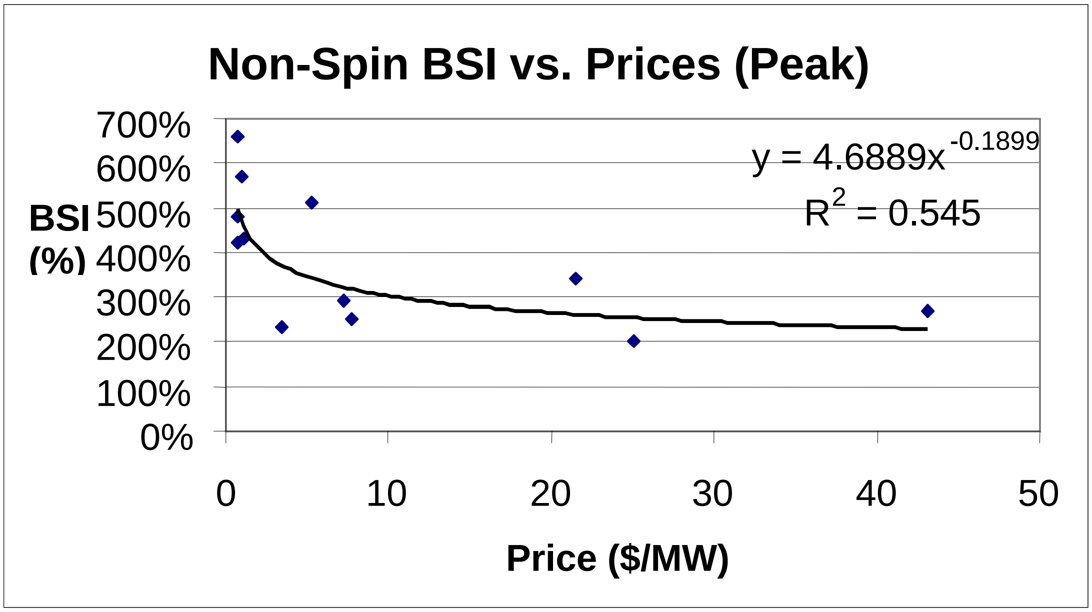

Figure 5 Non-Spin Reserve BSI vs. Price from 1 April 1998 to 31 March 1999 During Peak Hours With OLS Trendline (Source: CAISO)

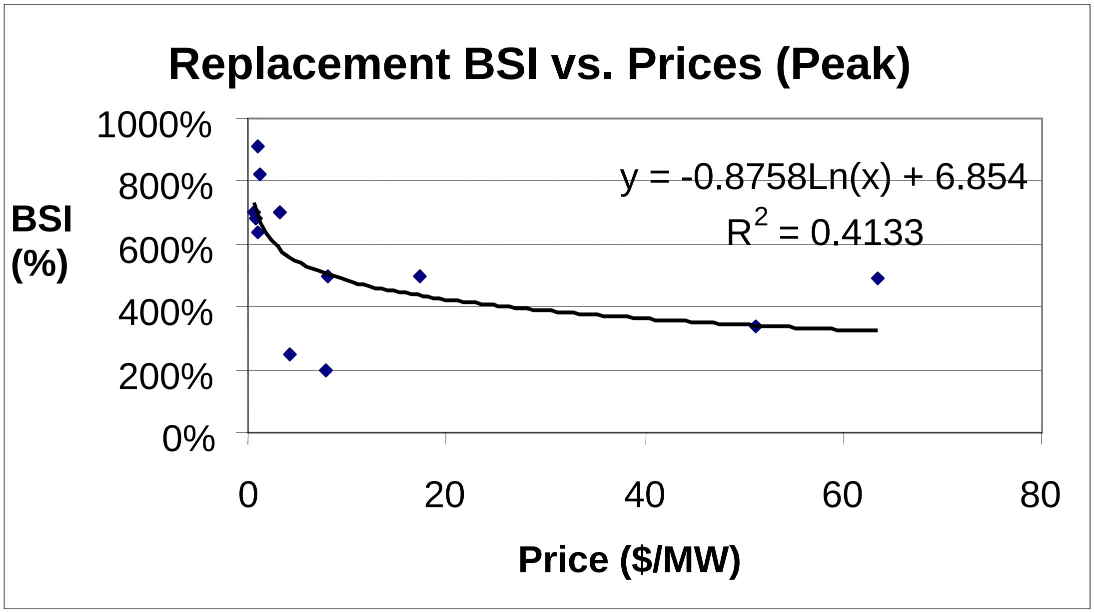

Figure 6 Replacement Reserve BSI vs. Price from 1 April 1998 to 31 March 1999 During Peak Hours With OLS Trendline (Source: CAISO)

It may be argued, on the contrary, that low values of the *BSI* are caused not by market power, but by scarcity. If this were the case, then the marginal costs of providing AS could also be high during periods of high prices. This would indicate that AS are expensive to provide due to scarcity, and thus, their market clearing prices are also high (since *price equals marginal cost* in competitive markets). To test whether price are deviating further from costs during times of low *BSI*, a short-run supply curve for the AS was constructed. Since information on the marginal cost of providing AS is obviously not readily available, marginal costs are estimated[11] as follows:

$$MC(t) = MC_{PX}(t) - fc(t)$$

where $MC(t) \equiv$ estimated marginal cost of AS in hour t
$MC_{PX}(t) \equiv$ estimated marginal cost of generation in hour t
$fc(t) \equiv$ natural gas price in hour t

The marginal cost of generation data are taken from Borenstein, Bushnell, and Wolak 1999, one of many studies on market power done by the University of California Energy Institute (UCEI). Using fuel costs as well as operating and maintenance (O&M) expenses and the average heat rate, Borenstein et. al calculate the marginal cost of each generator as well as its capacity. Therefore, the marginal costs of a generator are a function of its fuel costs, O&M expenses, average heat rate, maximum capacity, and forced outage factor. These figures are then used to construct the industry supply curve (also equivalent to the industry marginal cost schedule). Then, for each hour, the intersection of the electricity demand for that hour with the industry marginal curve identifies the marginal generator and its costs[12]. In order to obtain the estimated marginal cost for AS, the average fuel cost is simply subtracted from the marginal cost of generation[13].

We then calculate the average price markup by the generators:

$$A_i(t) = \frac{P_i(t)}{MC(t)}$$

Here, $P_i(t)$ is the price of AS type i in hour t. If $A_i(t) > 1$, then AS prices are greater than marginal costs, indicating some degree of market power. After the average price

[11] Note that in reality, the marginal costs of all AS would not be equal since it would cost more to provide a higher quality AS (such as regulation) than a lower quality one (such as spinning reserve). Since we don't have a methodology for measuring the impact of providing one AS over another, we assume for the purposes of this analysis that the marginal costs of all AS are equal.

[12] The heat rates are taken from the dataset maintained by the California Energy Commission (CEC) on Western System Coordinating Council (WSCC) generation for use in GE's MAPS multi-area production cost model. The fuel costs are taken from the Energy Information Administration's December 1998 *Electric Power Monthly* as well as from the MAPS dataset. Most generation used natural gas, so accordingly, the average weekly natural gas price at the California-Oregon Border was used. Finally, forced outage factors were taken from the North American Electricity Reliability Council (NERC).

[13] We ignore here the issue of opportunity costs.

markups for AS[14] are calculated, it can be seen that some of them are, in fact, greater than one (see Table 5). Furthermore, the greatest deviations from competitive pricing, i.e., high values of the price markup indices, occur precisely when there is low bid supply in the AS markets (see Table 6, Table 7, Figure 7, Figure 8, Figure 9, and Figure 10). From Table 6 and Table 7, it can be seen that there is a persistent negative relationship between AS price markups and *BSI* (with the exception of replacement reserve during off-peak hours). The plots of the *BSI* versus the price markups in Figure 7, Figure 8, Figure 9, and Figure 10 show that high price markups are, indeed, concomitant with low values of the *BSI*[15]. This evidence suggests that the price volatility in the AS markets resulted from a withholding of capacity by suppliers who were exercising market power (and not simply responding to scarcity). Indeed, if the high prices during periods of low bid sufficiency were due to scarcity, then marginal costs would also be high during these periods, indicating that AS bids from more costly generation are being accepted to meet high AS requirements. Our analysis shows no such evidence of higher marginal costs during these periods of possible scarcity. In fact, there is a clear negative relationship between the bid sufficiency and the average price markups. The factors that made capacity withholding possible involve market design parameters that provide arbitrage opportunities among the CAISO and CalPX markets. These factors are discussed at length in CAISO 1999a and Borenstein, Bushnell, and Wolak 1999.

PRICE MARKUPS					
Peak	*Regulation Price*	*Spin Price*	*Non-Spin Price*	*Replacement Price*	*PX Price*
Mean	0.53	1.46	0.87	0.95	1.26
Std. Dev.	0.79	1.85	1.27	1.38	0.44
Off-Peak	*Regulation Price*	*Spin Price*	*Non-Spin Price*	*Replacement Price*	*PX Price*
Mean	1.26	0.46	0.14	0.10	0.75
Std.Dev.	2.10	0.69	0.14	0.12	0.26

Table 5 Average Price Markups for AS and CalPX Markets in California (1 June 1998 to 30 November 1998)

Ancillary Service	*Correlation Coefficient*
Regulation	-0.715
Spin	-0.817
Non-Spin	-0.551
Replacement	-0.357

Table 6 Correlation Analysis of AS Markups with BSI During Peak Hours for 1 June 1998 to 30 November 1998 (Source: CAISO and UCEI)

[14] This is simply a transform of the *Lerner index*, i.e., $L_i(t) \equiv \frac{P_i(t) - MC(t)}{P_i(t)} = 1 - \frac{MC(t)}{P_i(t)} = 1 - \frac{1}{A_i(t)}$, where $L_i(t)$ is the Lerner index for supplying AS type *i* during hour *t*.

[15] Again, we fit OLS trendlines to the data that yield the highest R^2 values.

Ancillary Service	*Correlation Coefficient*
Regulation	-0.527
Spin	-0.949
Non-Spin	-0.831
Replacement	0.615

Table 7 Correlation Analysis of AS Markups with BSI During Off-Peak Hours for 1 June 1998 to 30 November 1998 (Source: CAISO and UCEI)

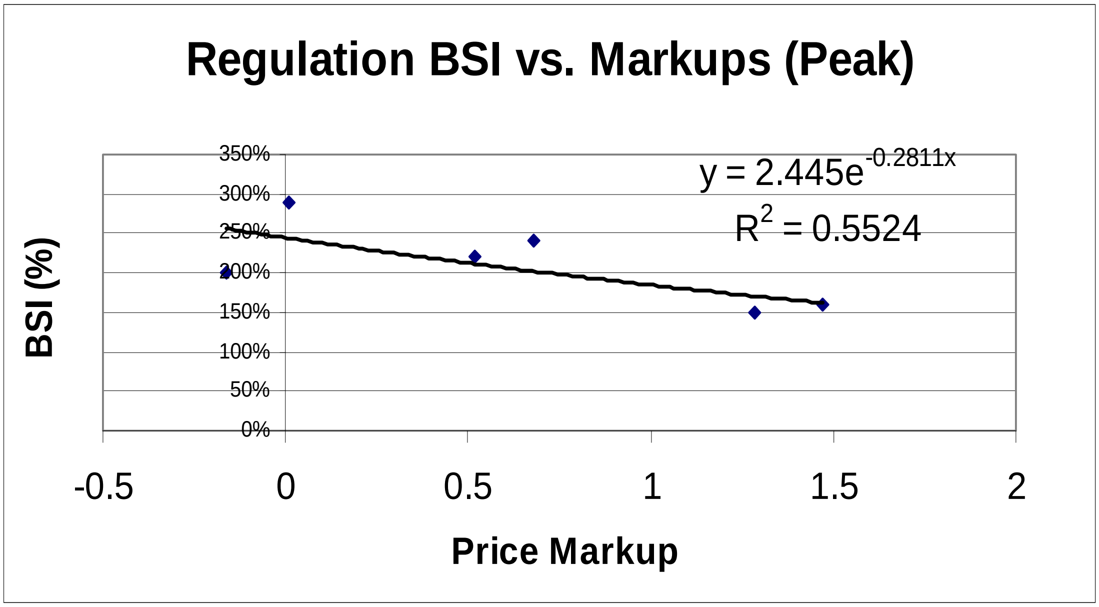

Figure 7 Regulation BSI vs. Price Markup from 1 June 1998 to 30 November 1998 During Peak Hours With OLS Trendline (Source: CAISO and UCEI)

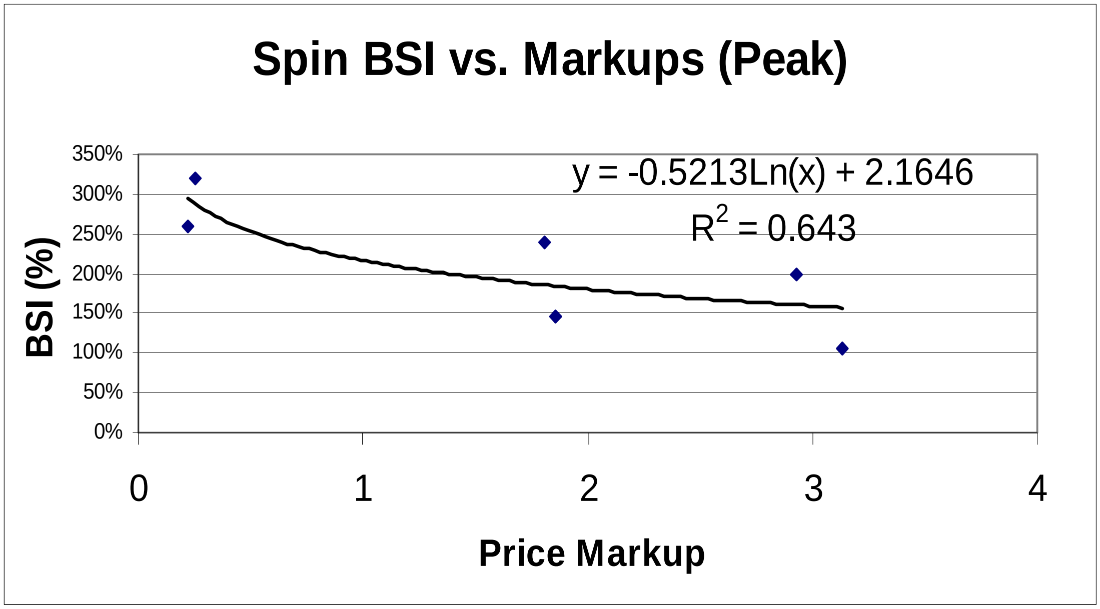

Figure 8 Spin BSI vs. Price Markup from 1 June 1998 to 30 November 1998 With OLS Trendline (Source: CAISO and UCEI)

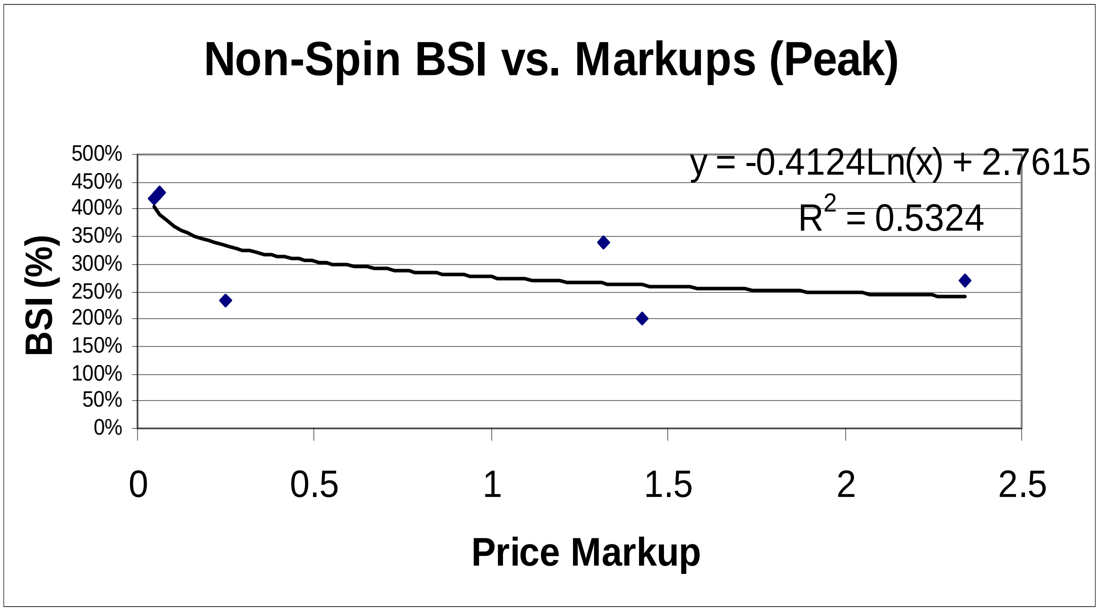

Figure 9 Non-Spin BSI vs. Price Markup from 1 June 1998 to 30 November 1998 With OLS Trendline (Source: CAISO and UCEI)

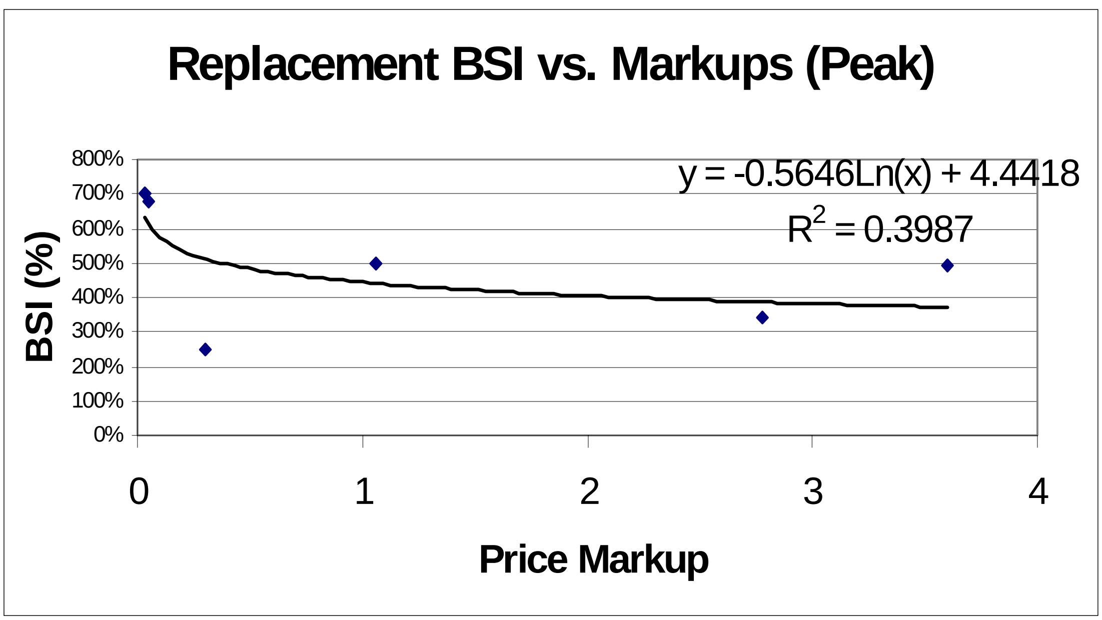

Figure 10 Replacement BSI vs. Price Markup from 1 June 1998 to 30 November 1998 With OLS Trendline (Source: CAISO and UCEI)

2.4. Effects of Price Volatility on the California Ancillary Services Markets

It is important to distinguish between price volatility that occurs due to market forces and that which is *imposed* on the market by agents with market power. Indeed, price volatility itself is desirable in a competitive market in order to provide economic signals to agents, who then promote efficient allocation of resources. For example, in the case of electricity, high on-peak prices will tend to constrain consumption when energy is needed the most, and periodic high prices, i.e., above marginal costs, are necessary to allow generators to recover fixed costs. If, however, price volatility is the consequence of departures from competition, e.g., through the exercise of market power, then it will impact negatively on social welfare as resources will be inefficiently allocated. Hence, it's not surprising that for the first year of operation in California, the total cost of procuring AS through the markets was about 12% of the overall CalPX energy value (see Table 8 and Figure 11), far exceeding the 3-5% range that was considered the engineering rule of thumb. Subsequently, prices have fallen significantly, and it seems that the *steady-state* value of 5-7% since January 1999 will be in line with expectations, or may fall even further. Therefore, while the excessive price volatility in the AS markets has raised the cost of procuring AS well above their historical values (and sometimes, even above the cost of energy itself), this may yet prove to be only a teething problem in the market. Clearly, while market power persists, some sort of price volatility limiting scheme is necessary to prevent such extreme fluctuations in AS prices, which are often not the result of competitive forces.

Regulation Cost	**Spin Cost**	**Non-spin Cost**	**Replacement Cost**	**Total AS Cost**	**PX Energy Value**	**AS Cost as % of Energy Value**
\$302M	\$140M	\$65M	\$68M	\$575M	\$5000M	11.42

Table 8 AS Cost Breakdown from 1 April 1998 to 31 March 1999 (source: California Energy Commission)

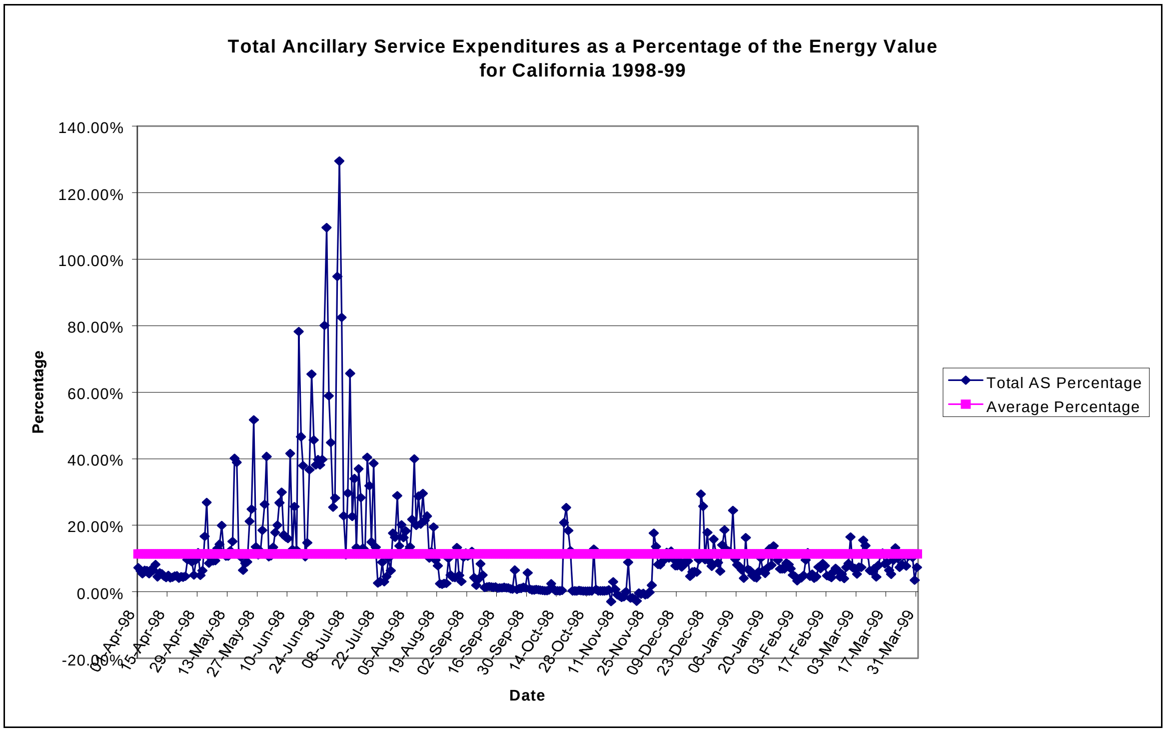

Figure 11 Total Weekly Cost of Procuring AS in California as a Percentage of the PX Energy Value from 1 April 1998 to 31 March 1999 (source: California Energy Commission)

3. CAISO's Initial Response to Price Volatility

3.1. Imposition of Price Caps

As a result of the highly volatile prices during the summer of 1998, the CAISO, with FERC approval, imposed price caps of $500/MW on all AS starting 14 July 1998. These were later revised to $250/MW in order to make them consistent with the CAISO's real-time energy and congestion management market price caps. Although these price caps were effective in reducing the price volatility of the AS markets (see Table 9), they were always viewed as a *stopgap* solution that would limit the damage inflicted by price spikes. In the meantime, the CAISO's Market Surveillance Committee (MSC) would attempt to devise a more effective procedure.

Ancillary Service	*Q1 COV*	*Q2 COV*	*Q3 COV*	*Q4 COV*
Regulation	0.47	1.40	1.56	0.30
Spin	1.16	1.19	1.42	0.45
Non-Spin	0.34	0.98	2.19	0.24
Replacement	0.29	0.97	1.84	0.17

Table 9 Peak Hour Coefficient of Variation (COV) by Quarter in the California AS Markets from 1 April 1998 to 31 March 1999 (Source: CAISO)

3.2. Proposal of a Price Volatility Limit Mechanism (PVLM)

In order to provide a smooth transition between the imposition of fixed price caps and an uncapped competitive market, CAISO management proposed a price volatility limit mechanism (PVLM) in the summer of 1999. Loosely related to the circuit breakers commonly used in other commodities markets, the PVLM would constrain the amount by which the price of an AS could move in one day. According to the CAISO, the PVLM was motivated by the following factors:

1. Allowing economic signals
2. Limiting the speed of price movements to allow demand-side response
3. Providing a transitional mechanism
4. Protecting against excessive price spikes[16]

Hence, it was to embody the trade-offs inherent in operating a market for electricity reliability services: on the one hand, providing protection against price spikes resulting from market design flaws, yet on the other hand, allowing economic signals to conduct efficient dispatch of services.

Although ambitious in its objective, the fundamental design of the PVLM is rather simple: it seeks to contain the maximum hourly price for a given day within certain bounds, but at the same time, adjusts the bounds to reflect market conditions. For example, if the maximum hourly price attained during day *t*, $p_{\max}(t)$, equals the designated upper limit for the day, $\overline{p}(t)$, then the upper limit for the next day is increased by the increment amount, δ (so $\overline{p}(t+1)=\overline{p}(t)+\delta$). Alternatively, if $p_{\max}(t)$ is *too low*, i.e., it falls below $\overline{p}(t)-\delta$, then the next day's limit is decreased by δ. Otherwise, if $p_{\max}(t)$ is between these two extremes, then the limit remains unchanged. Of course, there are variations on this design option that are triggered by market conditions or exist to protect agents from only the most extraordinarily high prices (e.g., greater than $2500/MW).

Perhaps the most obvious drawback of the PVLM is that it would not protect the market from *sustained* increases in the maximum hourly prices. For example, if $\overline{p}(t)=250$ and $\delta=100$, then a trend of steady increases in the maximum hourly prices would merely keep the upper price limit ratcheting upwards. Should such conditions persist, then there is no guarantee that the PVLM will prevent a situation that results in higher maximum hourly prices. Hence, while the PVLM prevents sudden extreme spikes and prevents the market-clearing price from spiraling out of control, it does not assure that an agent with strong market power will not be able to exercise it with impunity. Indeed, only the *rate* at which this agent is able to augment its price-cost margin is constrained (by δ).

Unfortunately, due to unfavorable stakeholder response, the CAISO Board of Governors rejected it during an August 1999 meeting in favor of universal price caps of $750/MW, which have since been reaffirmed by the Board. The CAISO Board's reasoning was that the market should be made as transparent as possible, and that economic signals (such as

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[16] California Independent System Operator (CAISO). *Price Volatility Limit Mechanism Issues and Options, July 1999* (available at http://www.caiso.com), 1999b.

high prices) will induce an increase in supply, thereby obviating all but the most extraordinary need for price controls. Furthermore, there were complaints from market participants that the proposed PVLM was too complicated and would not be practical to implement. These issues should, perhaps, have been investigated further (especially with the evidence of market power exercised by generators presented in Borenstein, Bushnell, and Wolak 1999). In the rest of this paper, the regulation of price volatility in other markets is examined and recommendations for the California AS markets are considered.

4. Regulation of Price Volatility in Other Markets

4.1. England and Wales

In light of the CAISO's reliance on price caps, it would be insightful to see how prices are controlled in other electricity markets. Here, we consider the case of the British electricity spot market that has been in operation since 1990. After restructuring, the generating assets held nationally by the Central Electricity Generating Board (CEGB) were divided among Nuclear Electric (NE), National Power (NP), and PowerGen (PG), with the former two acquiring only non-nuclear plants. Hence, in such a situation with only two suppliers and an inelastically demanded commodity (electricity), standard economic theory would suggest spot prices far in excess of marginal costs.

In spite of market conditions that favor extreme price markups, the wholesale price of electricity in the England and Wales pool has not exceeded the marginal cost by as much as expected. In Wolfram 1999, the factors that deter full exercise of market power are hypothesized to be regulatory constraints, the threat of entry, and financial contracts between suppliers and customers. Of these factors, the threat of regulatory action seems to have the greatest impact on depressing wholesale electricity prices. Indeed, after the regulator issues a statement concerning high wholesale prices, generators try to restrain prices in order to demonstrate to the public that they are not too high. This behavior by the generators is motivated in part by the power given to the regulator: if it finds that prices are too high, the regulator has the option of referring the generators to the Monopolies and Mergers Commission (MMC), the British antitrust enforcement agency. The MMC can then opt to break up NP and PG to form new companies. Clearly, since the generators do not want this step to be taken, they often voluntarily accept restraints on their ability to exercise market power.

4.2. Australia

The Australian states of Victoria and New South Wales (NSW) have been operating wholesale electricity markets since 1994 and 1996, respectively. On 4 May 1997, the National Electricity Market (NEM1) was established jointly by these two states. In Victoria, there are eight competitive generating companies, whereas in NSW, there are four. In Wolak 1999, it is shown that before restructuring, the average price of a MWh of electricity was \$AU35, which then fell to \$AU25 with formation of separate markets in Victoria and NSW. In NEM1, average prices have fallen further to \$AU15/MWh, which is close to the marginal cost of generation. Simple economic analysis of NEM1 shows that a typical firm can increase profits by 11-19% relative to current profits by holding fewer hedge contracts. However, due to excess generating capacity and risk-aversion on part of the generators, high levels of hedge contracts have persisted leading to lower prices and profits in the NEM1. This low-risk contracting also has feedback effects that tend to keep prices depressed: current low prices lead to low expectations of future prices, which encourages firms to sell hedge contracts at or near their marginal costs. This leads to aggressive bidding in the wholesale market, which makes the residual demand observed by any given firm more price-elastic, resulting in even lower prices and higher levels of contracting. Hence, according to Wolak 1999, an effective way to deter high price volatility and the exercise of market power in a restructured electricity market is to force a large enough quantity of hedge contracts on the privatized generators.

5. Conclusion

This paper has discussed some of the factors causing volatility in the California AS markets. Price volatility was defined and empirical evidence presented to support the claim that price volatility in the AS markets during the first year of operation exceeded that in the energy markets. Some of the possible causes of excessive price volatility were then suggested and examined. Focusing on the months with the highest levels of price volatility, simple statistical analysis supports the proposition that conditions favorable to the exercise of market power were concomitant with price spikes in the AS markets. In order to test the claim that such price spikes were merely indicators of economic scarcity, high average price markups in the AS markets were related to low bid sufficiency. Indeed, if these price spikes were simply indicating scarcity, then higher marginal costs (and therefore, stable price markups) would have been observed during those hours with low bid sufficiency.

CAISO's response to this excessive price volatility during the study period did not fully address the probable underlying cause of the price spikes experienced during most of the first year of operation: the exercise of market power by generators. CAISO has since made significant changes in market rules and other related regulations to deter perverse behavior, and more reforms are planned. In reviewing regulatory mechanisms used in other electricity markets, some rather simple measures (such as the mere threat of regulatory action or the use of hedge contracts) can be effective in tempering the exercise of market power and price volatility. Further study of these options should be pursued. Indeed, as long as the conditions that reward the exercise of market power in the California AS markets persist, the CAISO should continue market surveillance and examine policies enacted in other markets, rather than adopting solutions that are easy to implement.

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